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Submitted to Capacity Market: Hydrogen to Power and Interconnectors
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Yes

How did you hear about this consultation?

How did you hear about this consultation?:
Email from elsewhere

Other (please specify):

Participation of Hydrogen to Power

1 What are your views on Hydrogen to Power combustion plants connected to the wider hydrogen network and with natural gas connections participating in the Capacity Market under the existing gas Generating Technology Classes with the associated de-rating factors?

Enter your response in the text box below:

1.1 Hydrogen to Power (H2P) combustion plants that are connected both to the wider hydrogen network and retain a natural gas connection present a complex case for participation in the Capacity Market. Allowing these dual-fuel configurations to participate under the existing gas Generating Technology Classes (GTCs) may offer administrative simplicity, but it risks undermining both the accuracy of system adequacy assessments and the integrity of the Capacity Market's technology neutrality.

1.2 From a technical perspective, these hybrid plants do not behave identically to conventional gas-fired assets. Combustion characteristics, operational ramping, ignition control, and fuel switching protocols differ significantly when hydrogen is introduced. Even where hydrogen is blended at moderate levels, the reliability, flame stability, and emissions profile may diverge from that of natural gas. These differences have implications for both performance forecasting and capacity deliverability under stress events.

1.3 Furthermore, using existing gas GTCs and their associated de-rating factors assumes a level of operational certainty and field data maturity that does not yet exist for dual-fuel hydrogen systems. Applying these de-rating factors without adjustment could overstate the reliability of these plants, especially if hydrogen availability is dependent on upstream electrolyser supply or network constraints. Conversely, it may under-recognise the additional resilience offered by fuel-switching capability in specific configurations.

1.4 Therefore, while such plants should be eligible to participate, it would be prudent to define a new sub-category within the GTC framework or apply configuration-specific adjustments to de-rating factors. This approach would strike a balance between encouraging investment in flexible low-carbon capacity and maintaining the Capacity Market's central function: securing reliable supply during times of system stress.

2 What are your views on Hydrogen to Power combustion plants connected to the wider hydrogen network and without natural gas connections participating in the Capacity Market under the existing gas Generating Technology Classes with the associated de-rating factors?

Enter your response in the text box below:

2.1 Hydrogen to Power combustion plants that are connected solely to the wider hydrogen network, without any natural gas connection, represent a fundamentally different class of generation compared to traditional gas-fired plant. Treating these configurations under the existing gas Generating Technology Classes with their associated de-rating factors would be both technically and procedurally inappropriate.

2.2 These assets are wholly dependent on the availability, purity, and pressure of hydrogen supplied via a relatively nascent and still-developing infrastructure. Unlike natural gas, which benefits from a well-established and resilient transmission and storage system, hydrogen networks remain at an early stage of deployment and may be subject to greater volatility, especially during periods of coincident demand from multiple sectors.

2.3 Operationally, 100% hydrogen combustion introduces distinct challenges. These include higher flame speeds, greater sensitivity to mixing ratios, potential NO□ emissions, and differing start-up and turndown profiles. As such, their response to dispatch signals and performance under stress conditions may not align with the assumptions embedded in current gas GTC de-rating methodologies.

2.4 Applying unadjusted gas de-rating factors to these hydrogen-only plants could significantly misrepresent their contribution to system adequacy. It may either overestimate reliability during stress events—particularly if hydrogen delivery is constrained—or unjustly penalise newer technologies based on inappropriate benchmarks.

2.5 It would therefore be more accurate and transparent to create a dedicated Generating Technology Class for hydrogen-only combustion plant, accompanied by a bespoke de-rating methodology that accounts for fuel supply chain maturity, plant-level operational data, and stress period response capability. This approach would support the long-term credibility of the Capacity Market and send clearer investment signals for zero-carbon flexible generation.

3 What are your views on Hydrogen to Power combustion plants without access to natural gas, but with onsite storage, being categorised as duration limited and therefore participating in the Capacity Market under a Storage Generating Technology Class with the associated de-rating factors?

Enter your response in the text box below:

3.1 Categorising Hydrogen to Power (H2P) combustion plants without access to natural gas, but with onsite hydrogen storage, as duration-limited assets under a Storage Generating Technology Class is, in principle, a reasonable proposition—but only if the underlying classification framework is adapted to reflect the unique characteristics of such systems.

3.2 These configurations share some attributes with traditional storage technologies, in that their ability to deliver power is constrained by the volume of stored fuel. However, they differ in key respects. Hydrogen combustion plant does not exhibit the round-trip efficiency losses associated with battery storage, nor does it rely on electrical charging cycles. Instead, its performance depends on hydrogen production, compression, storage capacity, and the efficiency of the combustion system.

3.3 If these plants are to be treated as storage assets, the associated de-rating factors must be carefully calibrated to capture not only the storage duration but also the speed and reliability of fuel utilisation. For example, combustion start-up time, ramping behaviour, and thermal inertia must be taken into account. Furthermore, the availability and replenishment cycle of stored hydrogen should be scrutinised, especially during periods of extended system stress when fuel replenishment may be delayed.

3.4 There is also a question of fairness and market alignment. Traditional storage CMUs are often required to demonstrate firm output over a fixed duration, such as four hours. If hydrogen-based combustion assets are to be classified similarly, they must be held to equivalent standards in terms of discharge duration, availability testing, and response times.

3.5 Ultimately, the current Storage Generating Technology Class may not be fully suited to capturing the hybrid nature of these assets. A more appropriate solution may be to create a distinct “fuel-based duration-limited” category within the Capacity Market, which recognises the controllable but finite nature of onsite fuel storage, while still acknowledging the operational differences from electrochemical storage technologies. This would provide the necessary clarity and ensure that capacity contributions are valued appropriately.

4 If the government was to implement bespoke Generating Technology Class(es) for Hydrogen to Power plants, what factors would need to be considered when developing the de-rating factor? Please consider both combustion plants and fuel cells.

Enter your response in the text box below:

4.1 If the government were to implement bespoke Generating Technology Classes for Hydrogen to Power (H2P) plants, the development of associated de-rating factors would need to be grounded in a robust, configuration-specific methodology that reflects the operational realities of both hydrogen combustion systems and hydrogen fuel cells. These technologies, while both reliant on hydrogen as a fuel source, differ fundamentally in terms of performance characteristics, risk profiles, and contribution to system adequacy.

4.2 For hydrogen combustion plants, the following factors would be critical:
4.2.1 Fuel supply reliability: De-rating must account for the maturity and resilience of the hydrogen network or onsite storage arrangement. Plants with firm, redundant supply lines and sufficient storage to cover multiple CM stress events should be rated more favourably than those relying on single-source network delivery or volatile electrolytic production.
4.2.2 Start-up and ramping capability: Hydrogen combustion turbines may exhibit slower or less predictable start-up characteristics compared to natural gas units. This affects their ability to respond quickly to stress events and must be reflected in availability assessments.
4.2.3 Combustion dynamics and emissions controls: The propensity for NO□ production, flashback risk, and pressure fluctuations can impact operational continuity. Plants using advanced burner technologies or emissions mitigation systems should be recognised for their enhanced stability.
4.2.4 Operational testing and performance history: Given the novelty of these systems, any available field performance data—particularly from winter stress events—should carry significant weight in initial de-rating calculations, with scope for upward adjustment as reliability is proven.
4.2.5 Storage configuration: For combustion plants with onsite hydrogen tanks, the volume of stored fuel and the frequency of replenishment should be modelled against historical CM stress event durations and recurrence rates.

4.3 For hydrogen fuel cells, a different set of criteria would apply:
4.3.1 Continuous output profile: Fuel cells typically operate with high availability but are less suited to dynamic system balancing. Their de-rating factor should reflect their reliable baseload contribution rather than fast-response capability.
4.3.2 Electrochemical reliability: Degradation of the membrane and catalyst over time affects both efficiency and availability. De-rating must consider expected degradation curves, maintenance intervals, and historical failure modes.
4.3.3 Fuel purity and pressure sensitivity: Fuel cells are highly sensitive to impurities in hydrogen supply, which can cause cell poisoning or irreversible damage. Systems with integrated purification or redundancy mechanisms should be scored more favourably.
4.3.4 Modularity and redundancy: Many fuel cell installations are composed of modular stacks. A de-rating methodology could account for built-in redundancy, with partial capacity credit maintained in the event of stack failure.
4.3.5 Grid integration and controls: Some fuel cells are deployed as behind-the-meter or microgrid assets. Their dispatch control mechanisms and grid synchronisation capabilities should be considered in determining whether their capacity is truly firm and available to the system operator.

4.4 In both cases, the application of a static de-rating factor would be insufficient. A dynamic framework—responsive to operational performance, evolving infrastructure, and system needs—should be adopted. This would allow for a cautious initial rating, with scope for adjustment as technologies mature and confidence builds in their behaviour during real-world stress conditions. Such an approach would support fairness, system reliability, and investor clarity across the Capacity Market.

5 What wider factors (beyond Generating Technology Class(es) and de-rating factors) need to be considered to enable Hydrogen to Power to participate in the Capacity Market?

Enter your response in the text box below:

5.1 Beyond the development of bespoke Generating Technology Classes and appropriate de-rating factors, enabling Hydrogen to Power (H2P) to participate meaningfully in the Capacity Market will require a holistic approach that considers several wider technical, regulatory, and commercial enablers. These factors are essential to ensure that H2P technologies are integrated in a way that is both credible from a system security perspective and attractive to investors.

5.2 Fuel Availability Standards and Accreditation
The Capacity Market currently assumes that fuel will be available when needed. For H2P assets, the government must establish a formal framework to assess and verify the firmness of hydrogen supply—whether through network delivery, on-site production, or storage. This could involve introducing minimum fuel storage requirements, supply chain audits, or certification schemes similar to those used for interruptible gas.

5.3 Eligibility Criteria and Prequalification Processes
The prequalification rules must be updated to capture the specific features of H2P plant. This includes requirements for disclosure of:
- Fuel source and redundancy arrangements.
- Storage capacity and refuelling logistics.
- Emissions characteristics and combustion profiles.
- Technology maturity and operational history.
Such requirements should avoid placing disproportionate burdens on new technologies, while ensuring that only credible capacity is accepted.

5.4 Performance Testing and Stress Event Monitoring
New testing protocols will be needed to validate H2P performance. Standard CM testing based on dispatch instruction response may not capture the reliability risks associated with hydrogen systems. Tailored tests, including multi-hour sustained output demonstrations and simulated fuel switching, may be more appropriate. In parallel, actual performance during system stress events should be monitored to enable adjustment of obligations or future de-rating assumptions.

5.5 Commercial Incentives and Investment Signals
The Capacity Market alone may not provide a sufficient investment signal for H2P technologies, particularly given their capital intensity and early-stage deployment. Clarity is needed on how Capacity Market revenues will interact with other support mechanisms, such as:
- Hydrogen production subsidies (e.g., Contracts for Difference for electrolytic hydrogen).
- Industrial decarbonisation or heat network funding.
- Carbon pricing and emissions allowances.
Cross-market coordination will be vital to ensure that participation in the CM does not penalise projects for pursuing parallel decarbonisation objectives.

5.6 Connection Standards and System Integration
H2P plants—especially those operating with on-site hydrogen production—may have non-standard grid behaviours, such as variable start-up times or embedded generation characteristics. Grid connection standards, interface agreements, and dynamic system modelling processes must evolve to reflect these behaviours, particularly at distribution level where H2P may often be located.

5.7 Planning and Permitting Alignment
Permitting regimes must recognise the unique safety, infrastructure, and land-use implications of hydrogen combustion or storage. Delays in planning approval could create a bottleneck for prequalification, so close coordination between energy policy and planning authorities is essential.

5.8 Digitalisation and Data Transparency
As H2P technologies enter the Capacity Market, real-time and historic performance data will be crucial to informing market confidence, system planning, and future de-rating adjustments. The government and NESO should facilitate secure data sharing platforms that enable anonymised benchmarking, while protecting commercial sensitivity.

5.9 Long-term Policy Visibility

Finally, the long-term role of hydrogen in power generation must be clearly articulated within the UK's wider decarbonisation and energy security strategy. Investors will be reluctant to commit to projects without a stable policy trajectory for both hydrogen production and end-use. Alignment between the Capacity Market and the government's hydrogen strategy—including targets for production, infrastructure build-out, and end-use sectors—is therefore critical.

5.10 In sum, integrating H2P into the Capacity Market will require a coordinated package of technical standards, market reforms, and policy clarity. Only through such a joined-up approach can the government ensure that hydrogen contributes effectively to long-term system adequacy, while supporting innovation and low-carbon investment.

6 Are there any unintended consequences that could occur from enabling Hydrogen to Power to participate in the Capacity Market?

Yes

Enter your response in the text box below:

6.1 There are several potential unintended consequences that could arise from enabling Hydrogen to Power (H2P) to participate in the Capacity Market if the integration is not carefully designed and managed. These include:
6.1.1 Inaccurate Adequacy Forecasting: If H2P assets are assigned inappropriate Generating Technology Classes or de-rating factors—particularly by assuming they behave like conventional gas assets—this could lead to overestimating the reliable capacity available during system stress events. Such misrepresentation could reduce overall system resilience.
6.1.2 Market Distortion: Without clear and tailored eligibility rules, H2P assets may either be over-rewarded (if risk factors are not fully accounted for) or under-rewarded (if early-stage performance uncertainty leads to overly conservative treatment). Either outcome could distort auction results and undermine confidence in the Capacity Market's neutrality.
6.1.3 Disincentives for System Investment: If H2P participation is enabled before hydrogen infrastructure is adequately developed, this could lead to capacity clearing without sufficient supporting fuel supply. This, in turn, may defer or dilute investment in grid flexibility, storage, or conventional firm generation that remains critical in the short to medium term.
6.1.4 Increased Complexity and Administrative Burden: The diversity of H2P configurations—combustion vs fuel cell, with or without storage, blended fuels, etc.—could make prequalification, testing, and monitoring significantly more complex. Without streamlined processes, administrative costs could rise for both developers and market operators.
6.1.5 Carbon Intensity Uncertainty: Where hydrogen is not certified as low-carbon, its inclusion in the Capacity Market could lead to an inadvertent increase in overall system emissions, particularly if fossil-derived hydrogen is used without proper accounting or thresholds.
6.1.6 Double Counting and Cross-Market Conflicts: If H2P assets benefit from other policy support schemes (e.g., hydrogen subsidies, industrial decarbonisation grants), there is a risk of double counting capacity contributions or of overlapping obligations, unless clear rules are established.

6.2 Mitigating these risks requires a cautious, evidence-led approach to H2P participation—one that combines technological differentiation, robust data collection, and careful alignment with the UK's broader hydrogen and capacity adequacy strategies.

7 If you are an operator of an existing gas Capacity Market Unit, are you considering onsite blending of hydrogen and natural gas for power generation? Is the current Capacity Market framework sufficient to enable blending?

Yes

Enter your response in the text box below:

7.1 As an operator of an existing gas Capacity Market Unit, the prospect of blending hydrogen with natural gas for power generation is under active consideration. Onsite blending offers a pragmatic transition pathway toward lower-carbon generation without requiring a full redesign of the existing asset. It enables operators to demonstrate decarbonisation intent while preserving dispatchable capacity.

7.2 However, the current Capacity Market framework is not fully sufficient to support or incentivise this transition effectively. Several limitations remain:
7.2.1 Lack of Clarity on Classification: Blended-fuel configurations are not clearly recognised within the existing Generating Technology Classes. Operators are left uncertain as to whether blended units will be treated as modified gas CMUs, as hydrogen units, or fall into an undefined category—particularly if blend ratios exceed certain thresholds.
7.2.2 Inappropriate De-rating Factors: There is currently no mechanism to adjust de-rating factors based on blend composition or hydrogen proportion. A unit operating at 30% hydrogen may have materially different thermal and operational characteristics from one using 100% natural gas, yet the framework does not accommodate such distinctions.
7.2.3 Performance Testing Uncertainty: Blended-fuel operation may impact ramp rates, flame stability, or NO□ emissions, all of which could affect performance under Capacity Market testing. Without updated test procedures that reflect these variations, operators may face undue penalties or uncertainties in qualification.
7.2.4 Infrastructure and Safety Considerations: Onsite blending introduces new risks relating to pressure management, safety compliance, and fuel handling. These may not be fully recognised or supported within the current CM prequalification guidance or system modelling assumptions.
7.2.5 Commercial Disincentives: Given the additional operational and capital cost involved in blending systems—particularly retrofits—the absence of clear financial recognition within the Capacity Market reduces the commercial attractiveness of this decarbonisation pathway.

7.3 In summary, while operators are exploring onsite blending as a viable transitional option, the existing Capacity Market framework requires targeted reforms to classification, testing, de-rating, and guidance to ensure it is fit for purpose and supportive of low-carbon investment decisions.

8 Would the opportunity to blend hydrogen as part of your fuel mix incentivise you to bring forward new or invest in the lifetime extension of existing unabated gas capacity?

Yes

Enter your response in the text box below:

8.1 The opportunity to blend hydrogen as part of the fuel mix could serve as a significant incentive to either bring forward new gas-fired generation capacity or invest in the lifetime extension of existing unabated gas assets. However, this incentive would be conditional on several enabling factors being in place.

8.2 Why blending could support investment:
8.2.1 Transitional Decarbonisation Pathway: Blending hydrogen offers a credible way to reduce emissions from gas-fired generation in the near term, while maintaining dispatchable and flexible capacity. This supports both commercial viability and alignment with net zero policy expectations.
8.2.2 Regulatory and Political Signalling: Recognition of blending as a legitimate decarbonisation measure—especially within the Capacity Market framework—would provide reassurance to investors that transitional technologies are supported as part of the UK's pathway to net zero.
8.2.3 Asset Life Optimisation: For existing plant nearing the end of operational life, retrofitting for hydrogen blending may be more cost-effective than building new hydrogen-only assets. If supported by the market and regulators, this could unlock otherwise stranded capacity.
8.2.4 Operational Flexibility: The ability to switch between natural gas and hydrogen blends allows operators to respond dynamically to fuel availability, pricing signals, and emissions regulations, enhancing asset value and market resilience.

8.3 But the incentive depends on:
- Recognition in Capacity Market classifications and de-rating factors to reflect the technical profile of blended-fuel operation.
- Hydrogen availability and infrastructure readiness, including certainty of supply for blending at scale.
- Supportive emissions policies, including how blended generation is treated under the Emissions Performance Standard and carbon pricing regimes.
- Clear planning and permitting guidance, particularly for retrofits involving hydrogen infrastructure.

8.4 In conclusion, blending represents a viable and attractive investment trigger—but only if the policy and market frameworks evolve to explicitly support it. Without that, the risks and uncertainties may outweigh the potential benefits for many operators.

9 What are your views on how the government should approach Generating Technology Classes for hydrogen and natural gas blended fuel plants, including whether existing Generating Technology Classes are appropriate?

Enter your response in the text box below:

9.1 The government should adopt a forward-looking approach to the classification of hydrogen and natural gas blended fuel plants within the Capacity Market. Existing Generating Technology Classes, which have been developed primarily around conventional fossil fuel technologies, are not fully suitable for capturing the operational and risk characteristics of blended-fuel configurations.

9.2 Existing GTCs are insufficient for blended plant
9.2.1 Hydrogen blending introduces material changes in combustion behaviour, emissions profiles, ramping performance, and fuel supply risk. Treating blended-fuel plants as standard gas-fired assets under the current GTCs risks masking these differences and could lead to inappropriate de-rating factors, misinformed adequacy assessments, and unfair treatment—either in favour of or against such assets.
9.2.2 Additionally, the lack of clear classification creates regulatory ambiguity, which in turn undermines investor confidence and deters innovation in transitional decarbonisation solutions.

9.3 A dedicated GTC (or sub-category) for blended-fuel generation is needed
9.3.1 The most practical and fair solution would be to establish a dedicated Generating Technology Class—or at the very least, a defined sub-category—for hydrogen and natural gas blended fuel generation. This would:
- Allow for differentiated treatment based on blend ratios (e.g. below 20%, 20–50%, above 50%, etc.).
- Enable tailored de-rating factors that reflect actual performance data and technical risk.
- Create transparency for both market participants and policymakers regarding the contribution of these assets to system adequacy and decarbonisation goals.
9.3.2 Such a category would also facilitate consistent testing, compliance requirements, and reporting standards.

9.4 Classification should evolve with operational evidence
9.4.1 Any classification framework should remain flexible and evidence-based. Early-stage assets may face more conservative assumptions until field data becomes available. Over time, as confidence in the performance of blended-fuel plants grows, de-rating factors and participation rules can be adjusted accordingly.
9.4.2 The government should also establish clear thresholds for when a plant transitions from being classified as "blended" to "hydrogen-dominant," as this has implications for emissions regulation and funding eligibility under low-carbon support schemes.

9.5 Wider policy alignment is essential
GTC definitions must also align with wider government policy, including hydrogen deployment strategy, industrial decarbonisation plans, and the UK Emissions Trading Scheme. A consistent regulatory architecture across these domains would reduce confusion, enable cost-effective compliance, and accelerate market uptake of hydrogen technologies.

9.6 In summary, the creation of a distinct Generating Technology Class for blended-fuel hydrogen and gas plants would ensure regulatory clarity, improve market fairness, and send a strong signal that the government recognises transitional decarbonisation as both necessary and valuable. Relying on legacy GTCs would risk underestimating technical differences and misaligning the Capacity Market with the UK's broader energy transition objectives.

10 Are there any unintended consequences that could occur from enabling natural gas plants to blend hydrogen in their fuel mix?

Yes

Enter your response in the text box below:

10.1 While enabling natural gas plants to blend hydrogen in their fuel mix can support transitional decarbonisation, there are several unintended consequences that could arise if this policy is implemented without careful design and safeguards.
10.1.1 Overstatement of Emissions Reductions: Operators may claim significant emissions benefits from blending small volumes of hydrogen, even though the actual carbon savings may be marginal at low blend ratios. Without robust monitoring and reporting requirements, this could lead to inflated decarbonisation claims and undermine the credibility of the UK's net zero trajectory.
10.1.2 Misclassification in the Capacity Market: If blended-fuel plants continue to be treated under existing gas Generating Technology Classes, de-rating factors and performance expectations may not reflect their altered combustion dynamics. This could result in unreliable capacity being credited, or alternatively, in the unfair treatment of well-performing plant.
10.1.3 Technical and Safety Risks: Blending hydrogen with natural gas alters combustion characteristics—such as flame speed, ignition delay, and NO emissions. These changes could affect burner stability, asset integrity, and safety if existing infrastructure is not suitably upgraded. A poorly managed transition could lead to increased forced outages or safety-related incidents.
10.1.4 Incentive Misalignment: There is a risk that blending could divert attention and investment from more transformative low-carbon solutions, such as full hydrogen turbines or fuel cells. If capacity and decarbonisation revenues disproportionately favour partial hydrogen users, it could delay the development of more sustainable generation technologies.
10.1.5 Fuel Supply Constraints: If hydrogen blending is scaled rapidly without a parallel increase in low-carbon hydrogen production and delivery infrastructure, it may place stress on emerging supply chains and crowd out hydrogen use in sectors with greater decarbonisation need or efficiency, such as industrial heat or heavy transport.
10.1.6 Regulatory Ambiguity: Without clear policy and classification frameworks, blended-fuel generators could fall between regulatory regimes—uncertain whether they are subject to gas plant standards, hydrogen-specific requirements, or both. This could result in compliance loopholes or legal disputes.

10.2 In conclusion, enabling hydrogen blending in gas-fired power generation can offer real benefits—but only if supported by rigorous monitoring, classification reform, infrastructure readiness, and cross-sectoral coordination. Without these safeguards, the risks of misrepresentation, inefficiency, and unintended systemic impacts are substantial.

11 What wider factors (beyond Generating Technology Class and de-rating factors) need to be considered to enable hydrogen and natural gas blending for power generation in the Capacity Market?

Enter your response in the text box below:

11.1 Enabling hydrogen and natural gas blending for power generation in the Capacity Market requires a broad, systems-based perspective that goes well beyond Generating Technology Class definitions and de-rating factors. The blending of fuels introduces a range of technical, commercial, regulatory, and operational considerations that must be addressed to ensure the policy delivers genuine reliability and decarbonisation benefits without unintended consequences.
11.1.1 Fuel Standards and Emissions Monitoring: There must be clear regulatory standards for the composition of blended fuels, including accepted blend ratios, hydrogen purity requirements, and combustion characteristics. Without this, it will be difficult to ensure consistency across market participants or to assess the actual carbon intensity of the generated electricity. Robust emissions monitoring protocols should be put in place to verify claimed reductions and align with the UK Emissions Trading Scheme.
11.1.2 Infrastructure Readiness and Safety: The ability to blend hydrogen depends on the physical capability of turbines, burners, piping systems, and metering infrastructure. Not all gas-fired units are compatible with even modest levels of hydrogen blending. Technical standards must therefore be established for retrofit requirements, safety protocols, and pressure management systems. In parallel, the hydrogen delivery infrastructure—whether by pipeline, onsite electrolysis, or transport—must be sufficiently developed and reliable.
11.1.3 Fuel Supply Chain Resilience: Hydrogen availability will be a key determinant of whether blending is technically and commercially viable. The Capacity Market must consider the resilience and scalability of hydrogen supply chains, particularly during system stress events when fuel availability may be constrained. Contracts with suppliers, redundancy in delivery routes, and on-site storage will all be important indicators of capacity firmness.
11.1.4 Integration with Other Policy Mechanisms: Operators investing in blending capability may also be participating in other government support schemes—such as hydrogen production incentives, industrial decarbonisation programmes, or low-carbon heat initiatives. It is essential to ensure that capacity committed to the Capacity Market is not double-counted across multiple schemes or exposed to conflicting obligations. Cross-government coordination and a unified policy framework will be essential.
11.1.5 Capacity Market Prequalification and Testing: Blended-fuel units may exhibit different performance characteristics compared to conventional gas-fired units, such as changes in start-up time, ramp rate, thermal efficiency, or operational stability. Capacity Market prequalification processes and availability testing protocols should be updated to reflect these differences, ensuring that the system operator can rely on committed capacity during stress events.
11.1.6 Commercial Certainty and Investment Signals: Investing in hydrogen blending capability may require significant capital expenditure for retrofitting, safety systems, and control upgrades. Investors will require clarity on how such assets will be treated in the Capacity Market, what blend ratios qualify for modified classification, and how long any transitional rules will remain in place. Policy clarity and long-term market stability will be crucial to unlocking investment.
11.1.7 Grid Integration and Dispatch Coordination: Hydrogen blending could affect the operational profile of generators in ways that impact grid balancing. For instance, changes in flame stability or dynamic response may require more active coordination with system operators. Dispatch signals, balancing services procurement, and system modelling tools must therefore be updated to reflect the behaviour of blended-fuel assets.
11.1.8 Transparency and Data Collection: Finally, the introduction of blending into the Capacity Market must be accompanied by rigorous data collection and transparency. This includes tracking actual blend ratios, fuel sourcing, performance under system stress, and emissions data. This evidence will be critical for refining de-rating methodologies, informing future classification decisions, and evaluating the contribution of blending to long-term energy security.

11.2 In summary, enabling hydrogen and natural gas blending in the Capacity Market is not simply a technical adjustment—it is a multidimensional policy shift that touches on infrastructure, market design, emissions policy, and energy strategy. A coherent and well-integrated framework is essential to

ensure that blending supports both reliability and decarbonisation, without introducing new risks or inefficiencies.

12 Would you expect your plant to require more frequent maintenance / generation outages or incur higher maintenance costs to enable blending of hydrogen and natural gas? If so, could you provide estimated costs?

Yes

Enter your response in the text box below:

12.1 Blending hydrogen with natural gas is likely to result in increased maintenance requirements, more frequent outages, and higher operational costs, particularly in the early years of adoption. This is due to both the physical and chemical properties of hydrogen and the need to retrofit existing gas infrastructure, which was not originally designed to handle hydrogen blends.

12.2 Why more maintenance is expected:
12.2.1 Material Compatibility: Hydrogen can cause embrittlement in certain metals commonly used in gas turbines, pipework, valves, and seals. This can increase the risk of stress fractures, leaks, or premature wear, requiring more frequent inspection and replacement of components.
12.2.2 Flame Characteristics and Combustion Temperatures: Hydrogen burns hotter and faster than natural gas. This can lead to increased thermal stress on combustion chambers, nozzles, and turbine blades, accelerating degradation and shortening component life.
12.2.3 Control System Adjustments: Fuel blending may require more advanced control systems to manage dynamic fuel composition changes. These systems add complexity and may demand additional calibration and software updates, increasing maintenance overheads.
12.2.4 Emissions Management: Blending may increase NO□ formation, particularly at higher hydrogen ratios. Plants may need to install or upgrade low-NO□ burners or exhaust gas treatment systems, which come with their own maintenance burdens.
12.2.5 Estimated Costs (indicative only):
- Initial retrofit costs: £2–5 million per large CCGT unit (depending on turbine type and hydrogen ratio).
- Annual maintenance uplift: 10–20% increase over standard O&M costs.
- Planned outages: May increase in frequency from every 4 years to every 2–3 years for inspections of hydrogen-exposed components.
- Component replacement cycles: Some hot gas path components may require replacement 25–30% earlier than in natural gas-only operation.
These figures are based on early industry case studies and manufacturer guidance, and actual costs will vary based on plant size, age, blend ratio, and technology used.

12.3 In summary, blending hydrogen into natural gas will almost certainly increase maintenance demands and costs, particularly during the transitional period. While these costs may decline over time with experience and technological refinement, they must be recognised in any economic or policy assessment of hydrogen blending in the power sector.

Technical adjustment of interconnector de-rating factors in the Capacity Market

13 Do you agree that the government should implement an updated technical adjustment methodology? Please provide the rationale behind your view.

Yes

Enter your response in the text box below:

13.1 The government should implement an updated technical adjustment methodology for the Capacity Market, particularly in light of emerging technologies such as Hydrogen to Power, hybrid fuel systems, and increasingly complex interconnector behaviours. The existing methodology, while functional for traditional generation types, does not adequately capture the evolving risks, operational profiles, and reliability characteristics of these newer configurations.

13.2 Rationale:
13.2.1 Improved Accuracy in Capacity Adequacy Assessments: The technical adjustment process directly influences de-rating factors, which in turn affect how much reliable capacity the system believes it has available during stress events. Without updating the methodology, there is a risk that the Capacity Market will overstate contributions from newer technologies or under-credit transitional assets such as hydrogen-blended plants. This could compromise system reliability or create perverse investment incentives.
13.2.2 Recognition of Technology-Specific Risk Profiles: New technologies—including hydrogen combustion, fuel cells, long-duration storage, and duration-limited interconnectors—exhibit very different availability characteristics compared to legacy fossil or nuclear units. A revised technical adjustment methodology can allow these differences to be properly assessed and accounted for, enabling fairer treatment across the market.
13.2.3 Adaptability to Future Stress Events and Infrastructure Trends: The UK's electricity system is changing rapidly. Increased reliance on variable renewable generation, decarbonisation of heat and transport, and geopolitical risk to fuel imports all affect the stress patterns on the grid. A modernised methodology can incorporate a broader range of reliability data, including performance under extreme weather, fuel supply disruption, or high demand events, making the Capacity Market more resilient to uncertainty.
13.2.4 Alignment with International Best Practice: Other markets—including those in the EU and North America—have begun revising their reliability metrics, outage assumptions, and technology-specific adjustments to reflect the operational reality of hybrid and low-carbon systems. Updating the UK's methodology would maintain international credibility and promote investor confidence.
13.2.5 Transparency and Fairness: A transparent and evidence-based technical adjustment process helps ensure that all participants—new and existing—are treated fairly based on their actual contribution to security of supply. It can also provide clearer signals for innovation, retrofitting, and investment in flexible and low-carbon capacity.

13.3 In conclusion, updating the technical adjustment methodology is both necessary and urgent. It is the foundation upon which much of the Capacity Market's credibility rests, and without reform, there is a risk that capacity procurement will become increasingly misaligned with the realities of a

decarbonising and decentralising electricity system.

14 Do you agree that the government should implement the proposed methodology as detailed in Table 3? If not, please provide reasons why, or alternative approaches that could be considered.

Yes

Enter your response in the text box below:

14.1 I agree that the government should implement the proposed methodology as detailed in Table 3 for interconnector de-rating factors. It represents a balanced and data-driven approach that reflects the operational maturity of each interconnector and aligns with existing practices used by NESO for other conventional technologies.

14.2 Strengths of the Proposed Methodology:
14.2.1 Risk-Responsive Differentiation: By segmenting interconnectors into three categories based on years in operation (<1 year, 1–7 years, >7 years), the methodology sensibly recognises that availability and reliability improve as more empirical data becomes available. This ensures that new or less-tested interconnectors are treated more conservatively, which reduces risk to system adequacy.
14.2.2 Use of Winter Peak Periods: Focusing on availability during periods of high demand in winter is appropriate and prudent. It aligns with the fundamental purpose of the Capacity Market: ensuring firm delivery during periods of system stress. This avoids over-crediting assets that may perform well on average but are unavailable when most needed.
14.2.3 Moving Average Approach: For interconnectors between 1 and 7 years old, the use of a moving average allows for a smooth and adaptive transition as performance data accumulates. This also prevents abrupt changes in de-rating factors from year to year, giving investors more certainty.
14.2.4 Consistency with NESO Methodology: The alignment with NESO's approach for other major technologies (e.g., CCGTs and nuclear) supports fairness and consistency across capacity types. It simplifies modelling and enhances trust in the robustness of the technical adjustment process.
14.2.5 Flexibility for Refurbishments: The option to treat significantly refurbished interconnectors as "new" is a pragmatic inclusion. It acknowledges that material upgrades can significantly alter the technical characteristics and performance of an asset, justifying a fresh de-rating approach.

14.3 Minor Considerations for Enhancement:
14.3.1 Granularity by Route or Market Risk: While the methodology is solid, the government may wish to retain the flexibility to apply additional adjustments for specific interconnectors with heightened geopolitical or systemic risk (e.g., concentration on a single counterparty country or past unplanned outages due to fires or cable faults).
14.3.2 Transparency of Engineering Inputs: In cases where the adjustment is based on engineering data due to a lack of historical performance (<1 year), guidance should be issued to ensure that assumptions, model inputs, and third-party data are made transparent and subject to independent review.
14.3.3 Stress Event Simulation: Over time, the technical adjustment process could be strengthened by simulating performance during extreme scenarios, not just average high-demand periods. This could include coincident outages, low renewable generation, or peak market volatility.

14.4 In summary, Table 3 provides a sound and well-structured framework that reflects operational realities while maintaining alignment with broader Capacity Market principles. With some minor enhancements and a commitment to transparency, it will significantly improve the robustness of interconnector de-rating assessments.

15 Are there any unintended consequences to implementing the proposed methodology as detailed in Table 3? If so, please detail these.

Yes

Enter your response in the text box below:

15.1 While the proposed methodology in Table 3 for interconnector de□rating factors is well□structured and represents a marked improvement in accuracy and consistency, several potential unintended consequences could arise if it is implemented without complementary safeguards and periodic review.
15.1.1 Over□Penalisation of New Interconnectors: The conservative treatment of interconnectors in operation for less than one year, which bases technical adjustment on the minimum of available modelled or engineering data, could result in disproportionately low de□rating factors. This might discourage early participation by new assets or delay their entry into the Capacity Market. In practice, new interconnectors are often highly reliable due to new equipment and modern protection systems, so an excessively cautious approach could under□reward genuine capacity.
15.1.2 Inertia in Reflecting Performance Improvements: The use of a seven□year moving window for mature interconnectors may make it difficult for recent reliability improvements—such as upgrades, repairs, or replacement of converter components—to be reflected promptly in the de□rating factor. This could disincentivise refurbishment or proactive investment, since operators would have to wait several years for those benefits to appear in capacity credit valuations.
15.1.3 Potential Underestimation of Emerging Risks: Relying solely on historical availability data might overlook new and evolving risks such as cyber□security incidents, offshore cable interference, or increasing frequency of extreme weather events. These factors are not well captured in backward□looking averages and could lead to an underestimation of future outage probabilities.
15.1.4 Disparity Between Interconnector Routes: Interconnectors vary in their exposure to external system constraints—such as transmission bottlenecks or cross□border trading limitations in partner countries. The proposed methodology may not adequately differentiate between routes where availability is constrained by external factors rather than technical performance, potentially resulting in inconsistent treatment across the fleet.
15.1.5 Limited Transparency in Engineering Data for New Assets: For interconnectors with less than one year of operation, the reliance on engineering data or modelled characteristics could introduce subjectivity. Without transparent, standardised methodologies for these engineering assessments, there is a risk of inconsistency or perceived bias in the technical adjustments applied.
15.1.6 Administrative Complexity and Data Lag: Annual recalculation for assets within the 1–7 year range introduces operational complexity and potential delays in finalising de□rating factors ahead of Capacity Market auctions. If the data validation and modelling process is lengthy, market participants may face uncertainty when preparing bids.

15.2 While the proposed methodology provides a sound foundation, it may inadvertently discourage investment in new or refurbished interconnectors, fail to account for fast□evolving risk patterns, and impose unnecessary administrative burdens. These issues can be mitigated through periodic methodology reviews, enhanced data transparency, and the inclusion of forward□looking risk indicators alongside historical performance.

16 Do you agree that the government should generally exclude high-impact low-probability events from the technical adjustment calculation? Please provide evidence to support your view.

No

Enter your response in the text box below:

16.1 While it is understandable that high-impact, low-probability (HILP) events may distort short-term statistical averages, excluding them entirely from the technical adjustment calculation would weaken the core purpose of the Capacity Market: to ensure firm, reliable supply precisely during the most extreme and system-critical conditions.

16.2 Rationale:
16.2.1 The Capacity Market exists to manage system stress — not statistical averages: The fundamental purpose of the Capacity Market is to ensure that sufficient capacity is available when the system is under the greatest strain. HILP events—such as sudden interconnector failures during cold snaps, cable faults, geopolitical disruptions, or synchronous outages—are exactly the types of conditions that test system adequacy. Excluding these from technical adjustment models risks providing an overly optimistic view of asset availability.
16.2.2 Underestimating risk can lead to systemic consequences: If HILP events are omitted, the resulting de-rating factors will likely overstate capacity availability, reducing the volume of capacity procured in auctions. In turn, this could leave the system exposed during rare but highly consequential events—undermining consumer confidence and energy security.
16.2.3 Empirical precedent shows HILP events are not rare enough to ignore: Several examples over the past decade suggest that so-called HILP events are occurring with increasing frequency:
- The 2019 UK blackout caused by near-simultaneous loss of a gas-fired generator and an offshore wind farm.
- Fire damage to the IFA interconnector in 2021, removing 1 GW of capacity during a tight market.
- The 2022 Nord Stream pipeline incident and subsequent European energy market disruption.
These are not merely hypothetical outliers—they are real events with measurable system impacts.
16.2.4 Risk-adjusted modelling is better than outright exclusion: Rather than ignoring HILP events, the government should consider applying a risk-weighted approach. For instance, an HILP event could be partially included in the technical adjustment with reduced weight (e.g. using a dampened impact factor) or included in stress test scenarios that inform capacity margin policy but not de-rating factors alone. This provides a more balanced picture of risk without letting outliers dominate.
16.2.5 International alignment favours inclusion with moderation: Markets such as PJM in the US and ENTSO-E's methodologies in Europe do account for low-frequency high-impact events in their capacity and resource adequacy modelling. Exclusion would risk misalignment with best practice and reduce investor confidence in the UK regime's risk coverage.

16.3 The government should not generally exclude high-impact, low-probability events from the technical adjustment calculation. Instead, it should adopt a proportionate, transparent, and risk-aware methodology that reflects both the average performance and the tail risks that matter most for security of supply. Exclusion may be administratively convenient, but it is strategically short-sighted.

17 Please provide views on which, if any, criteria should lead a high-impact low-probability event to be excluded in the technical adjustment calculation? Please provide the rationale behind your feedback.

Enter your response in the text box below:

17.1 While high-impact low-probability (HILP) events should not be automatically excluded from the technical adjustment calculation, it is reasonable to define clear, evidence-based criteria under which some HILP events could be excluded or moderated, particularly if their inclusion would materially distort long-term risk assessments or unfairly penalise individual assets. A principled approach ensures both system adequacy and fair treatment of capacity providers.

17.2 Proposed Criteria for Considering Exclusion of a HILP Event:

17.2.1 The event was truly non-representative of asset class risk
17.2.1.1 Rationale: If the cause of the event is clearly external, non-recurring, and not reflective of typical operational risks, exclusion could be justified.
17.2.1.2 Example: A submarine cable fault caused by a once-in-200-year seismic event or a vessel anchor strike in a location where no shipping is usually allowed.

17.2.2 The outage was caused by force majeure beyond reasonable control
17.2.2.1 Rationale: Where the event is categorised as force majeure under the asset's operating licence or insurance policy—and could not have been prevented through commercially reasonable efforts—it may be unfair to let it drive down the de-rating factor.
17.2.2.2 Example: Political sabotage or armed conflict disrupting a cross-border interconnector.

17.2.3 There is verified evidence that robust mitigation was in place
17.2.3.1 Rationale: If the operator can demonstrate that all appropriate protections, redundancies, and industry best practices were in place at the time, the event should not be held against them in technical adjustments.
17.2.3.2 Example: An interconnector that was taken offline due to a rare software bug, despite having updated firmware, tested backup systems, and meeting all regulatory standards.

17.2.4 The event is clearly non-systemic and non-predictive

17.2.4.1 Rationale: If the event does not suggest any increased probability of future recurrence, and does not reveal a latent design flaw or infrastructure vulnerability, it may be reasonable to treat it as an anomaly.
17.2.4.2 Example: A crane collapse during nearby unrelated construction works causing a fire at a substation, where planning controls were otherwise followed.

17.2.5 The event has already been accounted for in broader system planning or stress test scenarios
17.2.5.1 Rationale: If the event is already modelled in national resource adequacy planning (e.g. NESO's Winter Outlook or National Risk Register), its inclusion in technical adjustments may double count the impact.
17.2.5.2 Example: Events integrated into formal resilience scenarios (e.g. concurrent cold weather and interconnector stress) may not need to directly adjust individual asset de-rating.

17.3 Additional Considerations:
17.3.1 Time Decay Mechanism: Even if a HILP event is included, its influence on the de-rating factor should diminish over time, especially if corrective action has been taken.
17.3.2 Weighting vs Exclusion: In many cases, partial weighting (e.g. assigning only 25–50% of the event's impact in the calculation) may be more appropriate than full exclusion, allowing the system to reflect rare risks without overreacting.

17.4 HILP events should be treated with measured judgement, not automatic exclusion. A clear set of criteria—centred on non-representativeness, force majeure status, mitigation efforts, and systemic relevance—offers a fair, transparent basis for deciding whether and how to include such events in technical adjustments. This approach strengthens both the credibility of the Capacity Market and the resilience of the electricity system.

18 Are there any unintended consequences to excluding high-impact low-probability events? Please provide evidence to support your view.

Enter your response in the text box below:

18.1 Excluding high□impact, low□probability (HILP) events from technical adjustment calculations may appear to simplify modelling, but it carries several unintended consequences that could weaken the robustness of the Capacity Market and compromise long□term energy security.

18.1.1 Underestimation of True System Risk: The Capacity Market's core purpose is to secure capacity during periods of maximum system stress. HILP events—such as interconnector fires, cable failures, or concurrent generation outages—are precisely the circumstances that test system resilience.
If such events are excluded from technical assessments, the government risks systematically underestimating the probability of shortfall. This may lead to smaller capacity procurements, reduced security margins, and increased exposure to blackouts during extreme conditions.
Evidence: The 2021 IFA interconnector fire removed 1 GW of capacity for months, contributing to high balancing costs and tighter margins that winter. Treating this as a statistical anomaly would misrepresent actual system risk, given that similar events have occurred in other jurisdictions such as BritNed and NemoLink.

18.1.2 Incentive Distortion and Moral Hazard: If operators know that extreme events will not influence their de□rating factors, they may have less incentive to invest in additional resilience—for example, in redundancy systems, enhanced fire protection, or proactive maintenance.
Exclusion could therefore weaken operational discipline and transfer greater risk onto consumers rather than incentivising mitigation by asset owners.
Evidence: Following the IFA incident, several interconnector operators voluntarily upgraded fire protection and cable monitoring systems. If those events had no bearing on future ratings, such improvements might not have occurred.

18.1.3 False Sense of Security in Market Modelling: Removing HILP data points can produce deceptively stable performance averages, concealing the tail risks that drive real□world system stress. This may lead policymakers to conclude that interconnectors or generators are more reliable than they truly are. Over time, this could result in the procurement of insufficient capacity or over□reliance on assets vulnerable to simultaneous failure.

18.1.4 Disconnection from Empirical Experience: Recent years have shown that "low□probability" events are occurring more frequently due to climate change, cyber□threats, and infrastructure ageing. Classifying them as outliers risks ignoring structural trends that are now integral to system planning.
Evidence: The European Network of Transmission System Operators (ENTSO□E) has noted a growing number of weather□related grid incidents across Europe between 2018 and 2024, many previously considered improbable.

18.1.5 Reduced Public and Investor Confidence: If a major disruption occurs that had been explicitly excluded from adequacy modelling, it may undermine confidence in the Capacity Market's integrity and credibility. Stakeholders would perceive that risks were underestimated or ignored, potentially affecting future investment appetite in low□carbon and cross□border infrastructure.

18.2 Excluding HILP events from the technical adjustment calculation introduces systemic blind spots, weakens incentives for resilience, and increases the likelihood of unexpected capacity shortages.
A more balanced approach—such as partial weighting, sensitivity testing, or time□limited inclusion—would preserve analytical rigour while avoiding the distortions that full exclusion could create.

Yes

19 Do you agree that the government should publish a briefing note to detail the methodology behind the technical adjustment? If there are certain aspects of the technical de-rating process that you think would be helpful to include in this briefing note or in future stakeholder engagement please provide details of these.

Yes

Enter your response in the text box below:

19.1 The government should absolutely publish a briefing note detailing the methodology behind the technical adjustment process. Transparency is critical to ensuring that the Capacity Market remains trusted, fair, and fit for purpose, particularly as the system integrates new technologies, fuel types (such as hydrogen blends), and more complex risk factors.

19.2 Why a briefing note is essential:
19.2.1 Promotes transparency and accountability: Publishing a clear, accessible explanation of the methodology used to determine technical de-rating factors allows stakeholders to understand how decisions are made and ensures consistent treatment across all technologies. It prevents the perception of arbitrary or opaque processes, particularly where outcomes impact commercial viability.
19.2.2 Improves investor confidence: The Capacity Market is a key pillar of long-term investment planning. Developers, financiers, and asset owners need to understand how their capacity will be rated—and re-rated—as system performance evolves. A formal briefing note helps reduce risk premiums and supports more efficient capital deployment.
19.2.3 Supports alignment with decarbonisation policy: As the energy system transitions towards net zero, capacity adequacy and emissions performance will become increasingly interconnected. Publishing the technical methodology allows stakeholders to assess whether the government is fairly incorporating decarbonisation pathways—such as hydrogen, storage, and low-carbon flexibility—into system planning assumptions.
19.2.4 Enables constructive engagement: A published methodology allows stakeholders, including system operators, academics, and industry bodies, to provide targeted feedback based on shared assumptions. This fosters a more mature and collaborative policy development process, particularly through consultation rounds or Technical Working Groups.

19.3 Suggested content for inclusion in the briefing note:
19.3.1 Data sources and time windows used
- Historical period covered
- Treatment of new plant or refurbished assets
- Handling of incomplete datasets
19.3.2 Treatment of high-impact low-probability (HILP) events
- Inclusion/exclusion criteria
- Weighting adjustments and rationale
- Examples of real-world events used in modelling
19.3.3 Calculation of moving averages and decay functions
- How different asset categories (e.g., interconnectors, storage, hydrogen) are averaged
- How outlier years are treated or normalised
19.3.4 Differentiation by technology
- Specific assumptions for CCGTs, OCGTs, battery storage, fuel cells, interconnectors, hydrogen blends
- Rationale for any bespoke treatment or exemptions
19.3.5 Approach to modelling future performance
- Whether forward-looking scenarios or stress simulations are used
- Integration of NESO Winter Outlook or Long-Term Forecasts
19.3.6 Process for updating the methodology
- Frequency of review
- Governance structure for updates (e.g. industry panels, stakeholder working groups)
- Role of NESO and Ofgem in validation and audit

19.4 A detailed, publicly available briefing note on the technical adjustment methodology is not only appropriate—it is essential. It will promote fairness, drive quality engagement, and ensure the Capacity Market continues to evolve in line with the UK's energy transition and security of supply objectives.

20 If you have further comments on the wider interconnector de-rating factor process, please provide details.

Enter your response in the text box below:

20.1 There are several important considerations regarding the wider interconnector de-rating factor process that should be addressed to ensure fairness, resilience, and system realism within the Capacity Market.

20.1.1 Interconnector-specific risk profiles must be accounted for: While it is reasonable to apply a common methodological framework across all interconnectors, in practice, not all interconnectors face equal operational or geopolitical risks. Factors such as route length, offshore vs onshore configuration, asset age, and single-point-of-failure vulnerabilities (e.g. converter stations) can significantly affect actual availability.
20.1.1.1 The de-rating process should incorporate:
- Route-specific historical performance, rather than fleet averages.
- Counterparty market stress correlations (e.g. links to markets likely to be experiencing simultaneous scarcity).
- Redundancy levels in infrastructure and control systems.

20.1.2 Cross-border policy and market divergence may undermine firm availability: The UK's reliance on interconnectors assumes continued policy and operational alignment with EU member states or other partners. However, market coupling arrangements, capacity export bans, or internal transmission constraints can prevent full utilisation of interconnectors during GB system stress, even when the asset is technically available.
20.1.2.1 De-rating calculations should therefore:
- Incorporate historical evidence of constrained flows during peak GB demand.
- Adjust for political and regulatory risk where countries have previously restricted exports (e.g. during the 2022–23 energy crisis).
- Reflect operational limits in partner TSOs' dispatch priorities that may affect the firm delivery of contracted capacity.

20.1.3 Availability testing must reflect real stress scenarios: Current de-rating assumptions are largely based on historic availability data, often averaged over time. This may not capture performance under actual system stress conditions, such as low renewable output, extreme cold, or high demand in both

interconnected markets.
20.1.3.1 NESO and the government should consider:
- Stress-event-specific availability scoring, similar to capacity performance penalties.
- Public reporting of interconnector flows during historic Capacity Market stress events.
- Modelling interconnector reliability conditioned on GB scarcity hours, rather than annual averages.

20.1.4 Need for forward-looking capacity modelling: Past availability is not always predictive of future performance, especially with increasing:
- Electrification of heat and transport.
- Demand-side response participation.
- Renewable penetration across Europe.
20.1.4.1 A forward-looking component should be introduced into the de-rating methodology, incorporating:
- Expected changes in flow directionality and market liquidity.
- Climate and extreme weather risk modelling, particularly for offshore assets.
- Geopolitical stress testing of interconnector reliability under high-impact scenarios.

20.1.5 Coordination with NESO and transparency in assumptions: To maintain trust in the Capacity Market process, it is essential that:
- NESO's modelling assumptions for interconnector contribution to adequacy are fully aligned with the capacity Market de-rating process.
- The underlying data—such as outage histories, availability curves, and forecast derated capacity—are made publicly available in an accessible format.

20.2 The interconnector de-rating factor process must evolve to reflect route-specific risks, market behaviour under stress, and the increasing strategic role of cross-border flows. A uniform approach may be administratively convenient, but only a granular, data-rich, and forward-looking methodology will ensure that the UK's reliance on interconnectors in the Capacity Market is justified and resilient.